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ADDENDUM TO UPGRADING CALIFORNIA'S ELECTRIC TRANSMISSION SYSTEM: ISSUES AND ACTIONS FOR 2005 AND BEYOND

STAFF REPORT ADDENDUM

Prepared in Support of the 2005 Integrated Energy Policy Report Proceeding (04-IEP-1F)

OCTOBER 2005
CEC 700-2005-018-AD

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Lynn Alexander
James Bartridge
Judy Grau
Clare Laufenberg Gallardo
Principal Authors

Robert Strand
Manager
ENGINEERING OFFICE

Sandra Fromm
Assistant Program Manager
2005 ENERGY REPORT

Kevin Kennedy
Program Manager
2005 ENERGY REPORT

Terrence O'Brien
Deputy Director
SYSTEMS ASSESSMENT AND FACILITIES SITING

B. B. Blevins
Executive Director

Abstract

This staff report addendum summarizes, in one document, information received at the California Energy Commission's (Energy Commission) July 28, 2005, Integrated Energy Policy Report (Energy Report) Committee hearing, written comments received through the August 4, 2005, deadline, and contractor work completed since the hearing. This addendum updates the Transmission Staff Report entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*. Together, the two documents provide background information for the Energy Commission to use in developing the *Strategic Transmission Investment Plan* (Strategic Plan) required by Public Resources Code Section 25324, as well as the transmission chapter of the 2005 Energy Report.

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ADDENDUM

Introduction

The purpose of this document is to summarize, in one document, information received at the California Energy Commission's (Energy Commission) July 28, 2005, Integrated Energy Policy Report (Energy Report) Committee hearing, written comments received through the August 4, 2005, deadline, and contractor work completed since the hearing. This addendum updates the Transmission Staff Report entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*.[1] Together, the two documents provide background information for the Energy Commission to use in developing the *Strategic Transmission Investment Plan* (Strategic Plan) required by Public Resources Code Section 25324, as well as the transmission chapter of the 2005 Energy Report. New contractor work, the proposed California Independent System Operator (CA ISO) transmission planning process, presentation slides, and written comments are available online at: http://www.energy.ca.gov/2005_energypolicy/documents/index.html#2005meetings.

Transmission Staff Report

The Transmission Staff Report published on July 20, 2005, represents a comprehensive assessment of the status of transmission planning and permitting; transmission system problems and project updates; long-term corridor needs; and transmission issues associated with renewables integration.

The Transmission Staff Report focused on five areas:

- Transmission policy status (Chapter 2).
- Transmission problems and project update (Chapter 3).
- Transmission corridor planning and development (Chapter 4).
- The impact of transmission on renewable development (Chapter 5).
- Transmission policy options (Chapter 6).

The Transmission Staff Report represents the staff's compilation of information and studies from several Energy Report Committee workshops. Committee workshops that focused on operational issues associated with integrating renewables were conducted on February 3 and May 10, 2005. The April 11, 2005, workshop focused on geothermal issues, and the May 9, 2005, workshop focused on both renewable resource potential in California and interstate renewable resources. The May 19, 2005, Committee workshop also focused on corridor planning and strategic transmission planning Issues.

July 28, 2005, Hearing

A Committee hearing on strategic transmission planning issues and the Transmission Staff Report was held on July 28, 2005, to seek public comment on issues relating to the Transmission Staff Report, the strategic transmission planning process, and a review of new contractor work completed after publication of the Transmission Staff Report on July 20. The hearing was webcast over the Internet. Interested parties were encouraged to present their views either in advance of the hearing, orally at the hearing, or in writing after the hearing. Reply comments were requested by August 4, 2005. Summaries of these comments were taken from the transcripts posted on the Energy Commission website.[2] Final contractor reports, presentation slides, and written comments are available online.

The notice for the hearing was posted on July 14, 2005. The agenda, presentations, and roundtable discussion questions were posted July 27, 2005, on the Energy Commission website. The hearing was conducted in coordination with Commissioner Peevey's March 14, 2005, Assigned Commissioner Ruling (ACR), issued in Rulemaking 04-04-003. The ACR noted that the Integrated Energy Policy Report Committee would conduct public proceedings, including any hearings necessary pursuant to Public Utilities Code (PUC) Section 1822 in its consideration of information to determine the likely range of the specific needs of statewide load serving entities (LSEs).

The following parties provided technical information or comments relevant to the hearing issues: Lawrence Berkeley National Laboratory (LBNL)/Consortium for Electric Reliability Technology Solutions (CERTS); Navigant Consulting; Pinnacle Consulting; the Energy Commission; San Diego Gas & Electric (SDG&E); Imperial Irrigation District (IID); Southern California Edison (SCE); Los Angeles Department of Water and Power (LADWP); Pacific Gas and Electric (PG&E); The Utility Reform Network (TURN), Flynn RCI, and the CA ISO. The presentation transcripts and slides are posted online and summarized in this addendum.[3]

New Contractor Work

Several contractor reports have been finalized since publication of the *Transmission Staff Report* and this addendum summarizes their key issues. The following contractor reports are available:

- *Proposed Criteria for Evaluation of Transmission and Alternative Resources*, Consultant Report, Publication No. CEC-700-2005-024. [http://www.energy.ca.gov/2005publications/CEC-700-2005-024/CEC-700-2005-024.PDF].
- *Assessing Low-probability, High-impact Events,* Final Consultant Report, Publication No. CEC-700-2005-020-F. [http://www.energy.ca.gov/2005publications/CEC-700-2005-020/CEC-700-2005-020-F.PDF].

- *Reliability Benefits of Economic Transmission Projects and Analysis of Congestion in Southern California*, consultant report, Publication No. CEC-700-2005-023-F [http://www.energy.ca.gov/2005publications/CEC-700-2005-023/CEC-700-2005-023.PDF].

Feedback on Transmission Staff Report and Strategic Plan

The July 28 hearing included a request for feedback on the Transmission Staff Report, *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*. Staff posed the following questions to solicit comments on the report:

a. Did the staff accurately capture parties' input?

b. Are there other relevant points?

c. Did staff draw appropriate conclusions?

d. Did staff identify appropriate policy options?

The July 28 hearing included a request for feedback on development of the state's first Strategic Plan. Staff posed the following questions:

a. Do the projects presented in Chapter 3 and Appendix F of the Transmission Staff Report provide an appropriate foundation from which to develop the Strategic Plan?

b. Which of the projects in Chapter 3 and Appendix F should be considered for inclusion in the Strategic Plan, and why?

c. Are there other projects that should be considered?

Comments on the Transmission Staff Report and Strategic Plan are detailed in the section below, entitled "Transmission Staff Report and Strategic Plan Input."

Summary of New Contractor Work

Review of Southern California Edison's Economic Evaluation Methodology for the Palo Verde – Devers No. 2 Line

Energy Commission staff retained the CERTS/Electric Power Group to review the CA ISO Board of Governors' February 2005 Report on the economic evaluation of the Palo Verde – Devers No. 2 (PVD2) Transmission Project. This work also included a similar review of SCE's *Environmental Assessment and Cost Effectiveness Report* (draft and final). In the July 28 hearing, Mr. Joe Eto of CERTS/Electric Power Group (CERTS/EPG) made a presentation on evaluating the strategic benefits and issues related to the social discount rate for the PVD2 project. (See pages 26-28 of the Transmission Staff Report, and the July 28 presentation attached to the *Transmission Staff Report*, as Appendix C. A discussion of the material is found in the transcripts on pages 6-26.)

The CERTS/EPG study reviewed the economic evaluation methodology that the CA ISO had undertaken and reviewed SCE's PVD2 economic evaluation. Mr. Eto noted that one of the key benefits is the opportunity for transmission to enlarge the market for generation. Transmission also contributes to price stability by enlarging the market and decreasing the market power of existing generators. Other benefits include reserve sharing and firm capacity purchases. Mr. Eto emphasized that these critical strategic benefit is an insurance policy against contingencies during abnormal system conditions and historically has not been captured in economic evaluations.[4]

Transmission projects also hold the potential for environmental benefits, including controlled pollutants and the reduced need for additional infrastructure such as gas lines. A critical recommendation made in the CERTS/EPG strategic assessment was the importance of a social discount rate that takes the weighted costs of a project into account over the project's lifetime.

SCE had several objectives in its economic analysis. Its primary objective was to access low-cost energy in the Desert Southwest. Accessing 6,500 MW on the PVD2 would significantly reduce costs for California ratepayers. SCE was interested in how this could affect competition since a new transmission line could expand the market for generation that might compete for load in California. SCE also considered the ability of infrastructure to support additional construction beyond assumptions currently in the generation portfolios. SCE noted the benefits of supply reliability, insurance value against extreme events, and the potential to operate the transmission grid more flexibly. However, since these items were not fully quantified, CERTS/EPG considered their value to be zero. Overall, CERTS/EPG therefore determined that the economic benefits of PVD2 were primarily energy cost savings.[5]

Update on Southern California Congestion

On pages 39-41 of the Transmission Staff Report, significant congestion issues and related costs were highlighted. Additional information on congestion was presented at the July 28 hearing by Navigant Consulting, LADWP, and SDG&E. A summary of those comments follows.

Navigant Consulting Presentation

Navigant Consulting presented information related to the congestion costs of Southern California's transmission lines. Palo Verde West, a branch group comprised of two 500 kV lines, the Palo Verde – Devers and the Palo Verde (PV) area to North Gila; the Imperial Valley – North Gila 500 kV line; and the Sylmar line between SCE and LADWP, are very congested. Navigant noted that generation in Mexico that feeds the Imperial Valley also contributes to congestion problems, as does as new generation in Southern California. A major difficulty with transmission is that generation can be built faster than transmission upgrades and projects, ultimately creating congestion on transmission paths.

An average of 3,500 to 4,000 MW has been added to the Palo Verde area over the last two to three years, further contributing to congestion costs. However, some transformer problems have been fixed.[6] There is speculation that if another 1,000 MW are added on the Southern California – Mexico border next year, transmission to mitigate congestion could not be built until at least 2010, necessitating a major project on the scale of PVD2.

The Miguel-Mission No. 2 Transmission Project has relieved some congestion by providing an additional 700 MW of capacity. It was recently put into service in a temporary configuration ahead of schedule, and a new 400 MW capacity transformer upgrade was completed in 2004.

There are several other projects in the works, the first of which is known as the East of the River 9000 Plus Project (EOR 9000+ Project), which is in the study stage. The project would include capacitor upgrades for 1,000 MW of operating capacity in the EOR area. If implemented, the PV branch group would get a pro-rata share for that path. Another project is the PVD2 (referred to in the presentation as Harquahala-Devers), for which the Western Electricity Coordinating Council (WECC) Phase 2 Study Report was just completed. The PVD2 project is expected to be in service by 2009 or 2010. The last project under study is a new line from Imperial Valley to the central or northern portions of the SCE system.

Navigant emphasized that congestion management costs consist of three components: redispatch costs (incrementing and decrementing), minimum load cost compensation (MLCC), and reliability must run (RMR) costs. Between July 2003 and September 2004, approximately $32 million was spent on redispatch alone, including decrementing Mexican generation and incrementing local San Diego generation. This is probably in the same range as the cost for the Miguel and Imperial Valley 230 kV transformers. The CA ISO also incurs MLCC and RMR operating costs. When those are added in, the actual expenditures for the congestion are much higher than $32 million.[7]

Quantification and Operational Reliability Benefits of Economic Transmission Projects

At the July 28, 2005, hearing, this effort was mentioned but no results or information were presented. Since the hearing, this effort has been completed and is contained in the consultant report entitled *Reliability Benefits of Economic Transmission Projects and Analysis of Congestion in Southern California.*

Assessment, LADWP/SCE Interconnection Issues

Navigant provided an overview of LADWP and SCE interconnection issues, starting with Sylmar Path 41 and Victorville – Lugo Path 63. The presentation showed how congestion costs underscore the need for additional interconnections. The slides for this presentation are available online.[8] Navigant noted there was a three-week Sylmar bank outage that was probably due to maintenance. This outage was very expensive and resulted in redispatching to relieve congestion.

Navigant presented a figure of monthly total redispatch congestion costs, by location, and their causes (see slide 20). Cited in the chart were the Sylmar bank outage of December 2003 that increased redispatch; the seven-week San Onofre Nuclear Generating Station (SONGS) refueling outage that increased Miguel bank congestion in February and March 2004; the Southwest Power Link (SWPL) work that decreased power flows; and the Miguel transformer bank congestion in May and June 2004. In July, August, and September 2004, Navigant noted a substantial increase in Sylmar bank congestion while upgrades to the Sylmar substation, part of the Pacific Direct Current Intertie (PDCI) transmission line, were under construction.

Navigant reported recent system upgrades by LADWP when a third transformer at Bank G in late 2004 increased the path rating to 1,600 Megavolt-ampere (MVA). Also, in December 2004, the PDCI terminal work was completed, resulting in reduced congestion and a more balanced flow across the transformers at Sylmar.

Some possible future system upgrades include repowering Haynes, Valley, and Scattergood with more efficient combined-cycle generation. Navigant noted it appears LADWP sometimes bids these resources into SCE and the CA ISO markets, resulting in congestion at Sylmar. LADWP disputed this statement, stating it does not bid resources directly into the CA ISO. Several other comments related to Sylmar congestion issues were also clarified by LADWP.

Navigant noted that if Sylmar congestion continues, additional interconnection capacity may be beneficial. Interconnection upgrades could include:

1. Rebuilding the Laguna Bell – Velasco 220/230 kV emergency tie to operate normally when closed.

2. New Adelanto – Lugo 500 kV line along with flow control devices at Sylmar to curtail flows.

3. Upgrading the Victorville – Century 287 kV lines to 500 kV, with a loop-in of the Lugo – Serrano 500 kV line into a new Upland Substation. This configuration could offer significant benefits to the LADWP and SCE systems.

As Navigant noted, congestion management is expected to send price signals for needed transmission upgrades. However, these signals are very expensive. Congestion costs for 10 months of operation could have paid for several new transformer banks. Navigant emphasized that a methodology or tool is needed to anticipate congestion so that transmission upgrades can be installed before non-productive congestion money is spent.

LADWP commented that it does not believe that the activity at Sylmar is a congestion and interconnection issue with SCE, noting that a transformer was installed last year that increased the transfer capacity to about 1,600 MW. The congestion appears to be related to a scheduled and planned upgrade of the Celilo-Sylmar Direct Current (DC) transmission line. Including the congestion during the outage related to the upgrade does not therefore appear appropriate.[9] Also, the emergency interconnection point with SCE is not normally used though it was used after the Northridge earthquake in 1994. This interconnection is not very robust and is not viewed as a reasonable interchange point.[10]

Development, Evaluation Criteria, Transmission, and Alternatives

Energy Commission staff retained Pinnacle Consulting to develop evaluation criteria comparing alternative resource portfolios on a state-wide level for possible use in long-term transmission planning, policy development, and implementation. The evaluation criteria could provide a framework for:

1. Developing a standardized, transparent evaluation methodology.
2. Developing statewide resource policies.
3. Comparing resource alternatives.

Before making recommendations, Pinnacle surveyed stakeholders and reviewed project alternatives including demand-side management, renewables generation, other generation alternatives, and transmission alternatives.

Pinnacle first presented the draft results of its study at the May 19, 2005, workshop; the final report was summarized during the July 28 hearing. The evaluation criteria were developed in consultation with stakeholders including agencies, consumer groups, environmental groups, generators, utilities, renewable groups, and transmission owners. Pinnacle recommends that these criteria be implemented in a “flexible framework” that could be adjusted for a particular project based upon its scope, preliminary economics, and available resources.[11]

In its final recommendations, Pinnacle proposed that six criteria be used as a framework to evaluate future resource portfolios and projects. These criteria should be computed whenever possible, though some criteria are subjective. The recommended criteria are:

- Least-cost
- Reliability
- Risk
- Market efficiency
- Fuel diversity
- Resource flexibility

The study is discussed on pages 25-26 of the Transmission Staff Report, and in the contractor report entitled *Proposed Criteria for Evaluation of Transmission and Alternative Resources.*[12]

Assessment of Low-Probability/High-Impact Events

Energy Commission staff retained Pinnacle Consulting to provide an assessment of low-probability/high-impact events. The draft consultant's report entitled *Assessing Low-Probability, High-Impact Events*, Publication No. 700-2005-020-F, notes that the economic evaluation of transmission projects has progressed to the point where a single base or reference case is often insufficient. In order to understand the impact of uncertainty on the expected value and distribution of economic benefits, multiple cases should be developed and evaluated. The purpose of the study is to provide a summary of the purpose of sensitivity cases; to summarize the recent CA ISO case study for PVD2; and to evaluate the proposed general methodology for conducting benefits assessment.

The value of transmission expansion is dependent upon a number of variables including load growth, fuel prices, hydro conditions, generation entry and location, market power, and others. Some of these can be easily quantified and others cannot. It is important to note that uncertainty should be considered with respect to transmission expansion benefits.

In the PVD2 study, the four key variables the CA ISO expected to significantly affect economic benefits were:

- Load growth throughout the WECC territory
- Hydro conditions
- Natural gas prices
- Generator market power

The CA ISO also used a scientific sampling method known as importance sampling to select a smaller but still representative number of possible cases that would represent the most likely conditions, extreme "bookend" conditions, and in-between conditions. Pinnacle reviewed the recent CA ISO case study of PVD2, noting that the CA ISO used three types of sensitivity cases in its evaluation:

- Cost-based cases
- Market-based cases with probabilities
- Contingency cases

Pinnacle concluded that the proposed general methodology for the selection and development of low probability, high-impact cases should consist of the following recommended tasks:

- Establish stakeholder process

- Develop reference case
- Select uncertain variables
- Develop variable distributions
- Select sensitivity cases
- Determine joint probability
- Perform simulations and summarize results

The presentation is contained in the transcripts on pages 47-80. The final report is available online.[13]

Transmission Staff Report and Strategic Transmission Plan Input

San Diego Gas and Electric

SDG&E presented a summary of its costs to permit the proposed Valley – Rainbow Transmission Line in 2001. This project was proposed to correct transmission deficiencies expected in 2005. The plan was to link the SDG&E system with SCE to the north, and provide another transmission corridor into San Diego at a cost of approximately $340 million. Permitting costs alone were estimated at $20 million. The project never passed the need phase, although the CA ISO had determined that it was needed.[14] Had the project been allowed to go into service in 2004 as requested, SDG&E stated that it would have saved its customers about $191 million in its first two years, because RMR costs from the MLCC side as well as the fixed option payment.[15]

Also in 2001 in the San Diego region, there was a significant increase in border generation. SDG&E worked with the CA ISO to identify the impact of new generation and moved forward to build the necessary transmission to mitigate congestion on its system. It took three years to permit a 230 kV transmission line on an existing right-of-way, the Miguel-Mission No. 2 Project (which also did not require substantial regulatory approval). By October 2004, the transformers were operational and a significant amount of congestion on the system was eliminated. This transformer capacity subsequently increased capacity from 1,000 MW to 1400 MW. With further recent improvements, the transfer capacity is now about 1,900 MW.[16]

SDG&E described the high costs of congestion. Without the Miguel-Mission No. 2 Project, the redispatch costs could have cost the utility about $32 million between 2003 and 2004. Over the last 12 months, redispatch costs have climbed closer to $48 million, and, if viewed over the next 12 months from July 2005 to June 2006 when the Miguel-Mission No. 2 Project will be completed, costs would have been far in excess of $50 million if SDG&E allowed this situation to go unchecked.[17]

SDG&E argued that transmission had to be built or generation would sit unutilized. The next major transmission line will be needed around 2010. Even with the addition of new generating plants coming on line in 2006 and 2008, San Diego does not have sufficient local generation to satisfy its peak load requirements. SDG&E must therefore look at another transmission line into the area.[18] It is likely that the next 500 kV line needed for reliability[19] will be from the East.[20]

SDG&E offered an example of just how tenuous the existing transmission system is in the San Diego area. On the morning of the July 28 hearing, SDG&E crews were repairing one of two lines to southern Orange County, serving 35,000-36,000 customers. Rains earlier in the year had damaged a number of footings beneath a single 138 kV corridor to Laguna Nigel. While the line was out of service for repairs, the only other line was lost - causing a blackout. SDG&E faces this type of situation every day and needs both new power plant facilities and more transmission.[21]

SDG&E also noted that the two power plants serving the area are at least 50 years old and that some of the "newest" units were installed over 30 years ago.[22] As a result, these plants have high operating Btu/kWh heat rates, typically 10,000 Btu/kWh and above. South Bay Unit 4 has a heat rate of 14,000. Furthermore, the South Bay power plant is located on land that belongs to the Port of San Diego, with a lease that expires in 2009.[23]

SDG&E presented an overview of its resources, transmission additions needed for 2005, 2008 and 2010, its future transmission outlook, reliability needs, access to renewables, and economics. In 2010, SDG&E anticipates a deficiency of about 333 MW, assuming that the Encina power plant continues to operate. In 2014, the number will increase to 700 MW. San Diego load is growing at rate of more than 100 MW per year. If any of the power plants retire, peakers are likely to be needed, along with another baseload power plant. San Diego has also made a commitment to renewable resources. Three years ago, the SDG&E renewable resource portfolio was less than 1 percent. When the state came out with the directive of 20 percent renewables by 2017, San Diego stepped up to the plate very aggressively. Today, renewables provide 5.7 percent of SDG&E's portfolio. SDG&E is currently negotiating contracts that will allow them to meet the 20 percent by 2010, but this target cannot be met without a new 500 kV line.[24] East of San Diego, in the Imperial Valley, are thousands of megawatts of potential wind, solar, and geothermal resources.[25]

All transmission lines need to be justified on economic grounds. If San Diego did not build the Miguel Mission No. 2 Line, sign the Palomar or Otay Mesa contracts, or build a new transmission project for 2010, their RMR costs would be approaching $350-400 million at a gas price of $5.00. If gas is priced at $8.00, costs would be an additional $200 million. So the Mission-Miguel No. 2 Project will undoubtedly pay for itself with the savings in RMR and congestion costs and the access to renewables.[26]

SDG&E noted additional complications: land use constraints east of San Diego include Indian reservations, military bases, national forests, and other public lands. Out of 200 linear miles of border, roughly 186 miles are protected by special interests, leaving about 14 miles of open access. Those 14 miles are currently “tied up” with homes. If SDG&E is unable to cross state or federal land, it will not be able to bring additional transmission into San Diego.[27]

Imperial Irrigation District

The Imperial Irrigation District (IID) presentation noted that the transmission information for Southern California was accurately portrayed. IID’s presentation slides are available online.[28] The IID described its transmission access as very limited and unable to meet its future needs. IID noted it has four major interconnections: to San Diego, SCE, Western, and Arizona Public Service (APS). The IID service area has one of the best geothermal resources in the state and there is potential for other green resources in the Imperial Valley. Therefore, IID sees a need for transmission.[29]

In response to questioning from Commissioner Geesman, IID stated that it is currently involved in technical evaluations and trying to encourage more participation in the Desert Southwest Transmission Project. The timeframe is expected to be 2008 or 2010. Controlling factors include the development of geothermal resources. IID noted it is important to get large-scale plants built so that transmission can be utilized. There also need to be agreements between California and Arizona both on what energy could be procured on a long-term basis to justify the financial impact of the transmission line, and the overall capacity that would need to be developed.[30]

IID stressed an essential part of the Strategic Plan: the importance of working together and planning joint projects. It described its efforts to work with various subregional transmission study groups, the CA ISO, the Southwest Transmission Expansion Plan (STEP) group, and the Southwest Area Transmission (SWAT) group. The Imperial Valley Study group has been helpful in promoting the green resources of the Imperial Valley. IID noted that because of its large region and western interconnect, joint transmission projects are needed.

Southern California Edison

SCE provided oral comments on the Transmission Staff Report as well as recommendations for the next Energy Report cycle. SCE comments begin on page 108 of the hearing transcripts.

SCE comments on the Transmission Staff Report and corridor process follow:[31]

- SCE used a recent event to illustrate its challenges with transmission. SCE had two subsequent days of all-time system peaks on July 26 and 27, 2005. During that period there were severe weather conditions in the area. An event occurred that has yet to be fully diagnosed. A fault on a 33 kV distribution network line out of the valley system may have precipitated what SCE believes was an air conditioner stalling event. On these very high load days, the voltage at Devers dropped to well below 500 kV, which can be especially devastating under these conditions.[32] This occurrence highlighted the importance of appliance standards for single-phase residential air conditioners that would require an under-voltage trip mechanism on the equipment so that in the event that there is a stalled condition, this doesn't perpetuate itself up to the transmission grid.

- "[W]e support the development of a comprehensive and proactive transmission expansion policy which includes a statewide planning effort to ensure the development of a strong transmission network in California. There is a critical need to improve and coordinate the planning processes for the siting and permitting and transition in California. The Transmission Staff Report is a major step in the right direction to develop such policy and coordination between the appropriate agencies; and SCE supports many of the proposals outlined in the report."[33]

- Implementation of the proposals in the report "must not create a duplicative process that would further burden any transmission planning process that really is today becoming quite burdened for our engineers."[34]

- Energy Commission staff was accurate in capturing SCE's input, and drew appropriate conclusions and policy options. "SCE wholly supports the development of a corridor planning process and a need identification process that would allow stakeholders, agencies, landowners and other interested parties to collaborate, cooperate, discuss, and resolve the issues associated with the corridor identification process, and the ultimate siting of transmission in the corridor."[35]

- SCE supported the creation of a corridor study group as outlined in the report, as well as the proposal to extend the time a utility is permitted to keep the cost of land acquired for future needs in its ratebase.

- The five-year land banking limit in existence today is not sufficient for utilities' long-term planning and adversely affects the development of transmission in critical areas of the state. The Energy Commission should to work closely with the CPUC to establish a proceeding to explore land banking issues.

- SCE fully supported coordination between utilities and the Planning Alternative Corridors for Transmission (PACT) program, to facilitate identification of transmission corridors and allow the public and decision makers to understand the pros and cons of specific, proposed, and alternative transmission corridors.
- SCE looks forward to participating in the establishment of a policy advisory committee and the technical committees proposed by staff as part of the PACT program.

- SCE favors establishment of a biological database to assess the environmental implications of transmission corridors to facilitate the more timely development of transmission facilities. Development of the database could both assist with the environmental assessment of those corridors identified in the corridor planning process and decrease the amount of time required for a utility to prepare an environmental impact report (EIR). Better information could ultimately help to conserve natural habitat.

- A transmission line sited in a particular corridor would not require a separate environmental assessment. A programmatic EIR could instead be created that is related to a specific corridor rather than a specific transmission project. "You can begin to look at environmental mitigation in total as a result of your corridor selections, your multiple corridors."[36]

- Energy Commission staff in its report entitled *A Roadmap for PIER Research on Biological Issues of Siting and Managing Transmission Line Rights-of Way*, issued in April 2004, noted that transmission corridors are often quite long, which can affect multiple habitat types and species within one corridor.

- Strategies that identify opportunities to promote conservation while maintaining system reliability could contribute to statewide conservation efforts, reduce negative public perception, and facilitate siting new, much-needed transmission lines.

- SCE supports Public Interest Energy Research (PIER) environmental assessment funding recommended by staff to establish tools and methods to facilitate the environmental assessment of selected or designated corridors. SCE supports staff's proposal and strongly encourages the Energy Commission to reexamine process and proposals related to the environmental assessment of selected or designated corridors.

- SCE supports the Transmission Staff Report's assessment that the integration of renewables will further complicate the existing frequency support problems on the grid. SCE supports further research on the issue to better understand the operational implications of integrating large amounts of non-dispatchable and intermittent resources in a safe, reliable, efficient, and cost-effective manner.[37]

- There are additional operational and planning costs that utilities may incur in order to integrate a significant amount of additional intermittent and non-dispatchable renewable power. The Energy Commission's *2005 Energy Report* focused on this issue. The Energy Commission's operational integration work, initially undertaken by the staff, should continue through a collaborative effort. This is of particular concern to SCE because the majority of identified renewable and wind potential in California is located in or near

SCE's service territory. This fact, coupled with the state's desire to significantly increase renewable resources, creates a high likelihood that SCE will be required to integrate ever-increasing amounts of intermittent and non-dispatchable resources potentially far in excess of its own obligations.

- The section in the report recognizing the importance of educating the public about the function of a transmission grid "is necessary, but something that we want to undertake very carefully because of the security concerns and vulnerabilities of the grid."[38]

- Transmission serves many functions, and this year's report focused on generation, integrating generation, market functioning, and how transmission is developed in response to that. SCE noted that, perhaps next year, staff needs to give some thought to load: how load develops, where it develops and how that can affect the grid. It would be helpful to know how populations move, how new homes and communities are created, so that we might be able to do a better job in expanding the transmission grid, and also working with cities and counties to do a better job of planning the infrastructure necessary to serve their own growth.

Los Angeles Department of Water and Power (LADWP)

The LADWP also provided testimony at the July 28 hearing, and followed up with written comments available online.[39] LADWP began its presentation by noting its commitment to the transmission planning process and promising greater involvement and participation in the Energy Report process. The representative introduced an LADWP employee who is relocating to Sacramento specifically to work with the Energy Commission and the legislature.

A recent event occurred in Los Angeles, when the utility was hit with an all-time record of peak demand that was exceeded the following day (5,708 MW). This record was hit despite the loss of the single largest generating unit of the Intermountain Power project. LADWP believes it may have been caused by a lightning strike somewhere in Utah. Although it had to curtail sales, it was able to maintain system reliability with imports from Nevada and Arizona.

The activity at Sylmar is not a congestion issue, contrary to a comment made by Navigant on congestion charges.[40] LADWP installed a transformer last year that increased transfer capacity, but stated it was not related to the Sylmar facility. The congestion appears to be related to a scheduled and planned upgrade of the Celilo – Sylmar DC transmission line, which provided benefits for the state. Looking at the congestion that might have occurred when that upgrade was happening is probably not something that should be used in other forums. In addition, LADWP clarified its interconnection points with SCE, noting that there is an emergency tie that is not used and not viewed as a reasonable interchange point.[41]

LADWP is a founding participant of WestTrans. One benefit of this participation is gaining greater efficiency from its existing transmission. Efficiency should be a goal, instead of just planning and preparing new transmission. The membership of WestTrans includes most of the utilities in the western states. It is important that the CA ISO be a participant in WestTrans.[42]

LADWP clarified that it did not make sales to the CA ISO and its credit risk policy with the City of Los Angeles does not allow it to make sales directly to the CA ISO, contrary to information in the Navigant report. LADWP has bilateral contracts with other parties including SCE and SDG&E.[43]

Some of the projects that LADWP is considering include the Owens Gorge 230 kV line, which runs very near the Tehachapi area and will serve a large portion of future renewable requirements. LADWP has remaining 160 MW that could be used for a tie-in with renewables. It believes the line could be upgraded to a 500 kV line.[44] LADWP also dedicates about 170 MW for hydroelectric power out of the Owens Valley and has reserves of about 120 MW from the Pine Tree Project. Part of the Pine Tree Project is to build an 11-mile spur from north of Mojave into the Tehachapis.[45]

LADWP emphasized it is committed to both new transmission and the process identified by the Energy Commission. LADWP believes this is a very significant movement to build transmission, and that there is value for California's ratepayers. Los Angeles' transmission costs are some of the highest in the state, while generation costs are among the lowest.[46]

Pacific Gas and Electric

PG&E provided comments on the corridor identification, designation and right-of-way process, and updated information on PG&E's projects described in Chapter 3 and Appendix F of the Transmission Staff Report.

PG&E offered some suggestions on collaboration:[47]

- There needs to be collaboration on ways to expedite the California Environmental Quality Act (CEQA) process, with better coordination of activities in general through the process.

- There should be adequate consideration by one agency of another agency's expertise and regulations. That way duplication of work will be minimized.[48] PG&E indicated that land acquisition banking and early corridor designation can help expedite the transmission siting process, "but only if we don't have to do it all over again."[49]

- PG&E is concerned that once a corridor is identified, it impacts land values and communities. This could create potential "taking" issues. Therefore, PG&E needs some clear support from the Legislature and local agencies before it proceeds.

- Transmission projects have two broad purposes: to accommodate new resources and reduce operating costs and provide operating flexibility and to supply load reliably. While there is uncertainty associated with both purposes, there is more uncertainty related to resources. A utility can project load growth, but with resources there is no control over where, when, and how much resources can be developed. Resources can be developed a lot faster than transmission can be built. Therefore it is important to take a big-picture approach.

- To keep the process manageable, one needs a simple approach to start, and that can be expanded. One should identify a few corridors that would meet many potential needs instead of numerous corridors going to every potential growth area. There must also be flexibility so that the corridor identification process can be adjusted later as new information develops.

- PG&E suggested the following steps:[50]

    - The Energy Commission develop a number of resource scenarios for the entire state similar to the Strategic Value Analysis (SVA) effort. The CA ISO and the transmission owners can then develop a transmission plan to accommodate resource scenarios through a stakeholder process.

    - Reduce uncertainty by selecting transmission projects that are common to a number of credible scenarios. One credible scenario can be laid over another. Sooner or later a pattern of transmission projects will emerge that could be beneficial in a number of scenarios.

    - A transmission project common to more scenarios could be given a high priority. The Energy Commission could track resource projection development and provide updates to the scenario. They could then be incorporated into the next transmission corridor identification cycle.

- PG&E noted its concerns about the corridor designation process:[51]

    - The Energy Commission's proposed corridor designation process appears to require determination and the need to prepare a proponent's environmental assessment (PEA). Preparation of a PEA is time-consuming and costly – in the tens of millions with a full-blown PEA and a Certificate of Public Convenience and Necessity (CPCN).

    - Cost recovery is very important to PG&E, but the cost to customers and the impact on the community must also be primary considerations.

- Transmission is under Federal Energy Regulatory Commission (FERC) jurisdiction, so PG&E must also work with FERC because FERC rules state that the transmission owners cannot recover the cost of obtaining a permit until the associated project is operational.

- PG&E is concerned about the scenario in which it obtains a permit today and the project is delayed, or may not be built for many years. This delay in cost recovery provides support for an incentive to designate, acquire, and bank rights-of-way.

- CPUC support would be needed for this cost recovery.

- PG&E agreed, in response to a request from Commissioner Geesman, to ask its legal division to review the Energy Commission's staff recommendations for lengthening the time that the CPUC will allow a utility to carry land in its ratebase, and how FERC's jurisdiction would be triggered. Commissioner Geesman understood that the staff recommendation focused on right-of-way acquisition in advance of actual FERC approval.[52] PG&E was concerned that it would need an expensive permit which may require a PEA, while the question remained about FERC jurisdiction. Commissioner Geesman reiterated that this is a good reason for the PG&E legal division to review the issue.

- PG&E stressed the overall uncertainty of transmission planning. It believes that the actual purchase of designated right-of-way ahead of actual need is unnecessary and would not expedite the siting process since it has a permit it would take only months to acquire the right-of-way. PG&E cited the example of building the Pacific Intertie some years ago, when there was also some thought of building a third intertie down the east side of the valley. Some of that right-of-way was purchased but later not needed. When the California-Oregon Transmission Project (COTP) was built, essentially a third intertie, it was instead sited on the west side of the valley.

- PG&E also commented that the web-based model should not replace on-the-ground assessment, although it is a good tool. Commissioner Geesman stated that he had heard similar comments from other different utilities and that it would be highly informative if the utilities could develop a common position. Commissioner Geesman noted that "I don't think anybody wants to encourage the expenditure of ratepayer funds for something that is ultimately not useful."[53]

The PG&E presentation also included project updates to the projects described in Appendix F of the Transmission Staff Report:[54]

- The Jefferson-Martin 230 kV line is making good progress. It is expected to be operational in the first half of 2006. Hunters Point should be shut down in 2006 following the energizing of this project.

- Project # 2, the San Francisco/Peninsula Long Term (2011+) Upgrades, and Project # 3, the Trans-Bay DC Cable Project, could be the same project, depending upon the cost and need. Stakeholders and the CA ISO are still evaluating alternatives. A project is needed by 2012 at the earliest.

- Project # 5, Greater Fresno Area Projects, includes the Henrietta-Gregg Reconductoring Project that has just received CPUC approval. PG&E plans to build it in 2006.

- Project #16, the Tehachapi Area Renewable Interconnection Project. PG&E supports the renewable portfolio standard (RPS) target and schedule and will work to make sure that the most cost-efficient solution will support the state goal. It is unclear whether there may be a direct interconnection to Tehachapi, but studies are currently underway. The identified problems north of Midway would first need to be resolved. However, a direct line from Tehachapi to Midway line is not needed until there is a need to schedule more than approximately 1,500 MW to Northern California.

California Independent System Operator

The CA ISO provided an overview of the existing transmission process and the CA ISO's proposed transmission planning process. The draft plan is summarized in the CA ISO's oral comments below. The full document is posted on the Energy Commission website and the CA ISO website http://www.caiso.com/.

The CA ISO emphasized its interest in working with all the participants to develop a statewide transmission planning process. The Transmission Staff Report had captured the momentum of the work the CA ISO has been doing with the CPUC and the Energy Commission. The CA ISO has core strengths to bring to the table and can work out a process that involves the appropriate agencies to accomplish this goal.[55]

The CA ISO provided a summary of the current transmission planning process:

- The current process has been used since the CA ISO has been in operation and is described in the tariffs.

- Participating transmission owners (PTOs) develop an annual transmission expansion plan, which looks out roughly 10 years. The first five years have the most detail and that detail is used for budgeting. They look at the plans, identify problems, and then propose projects to resolve those problems. They look at the projects that are most economic, include them in the expansion plan that is provided to the CA ISO. Then the CA ISO reviews the projects that cost $20 million or greater, as they will require CA ISO board approval. Projects that cost less than $20 million can be approved by CA ISO management.

- The CA ISO also does a control area or control grid study. This combines all three expansion plans into one. There has been a lot of discussion about how this could be done a statewide basis. So the CA ISO is about as close as it can be to coordinated transmission planning. CA ISO's jurisdiction covers about 75 percent of the state. "But clearly, there are missing pieces...that are really important..."[56]

- The CA ISO also manages RMR work which involves an annual process. CA ISO only looks at the next year in determining what RMR requirements are for that year. There is a process to identify the generation needed to meet those requirements. The CA ISO sees this as a reactionary process.

The proposed CA ISO transmission planning process is a proactive process:

- The CA ISO President and Chief Executive Officer (CEO) has decided that the CA ISO should take a more proactive role in the transmission planning process as the CA ISO has information that is not readily accessible by others. The CA ISO realizes that the work it does with RMR and congestion provides opportunities to be more proactive and find ways to reduce these costs.

- The CA ISO has identified RMR costs at roughly $600 million, and congestion costs at around $300 – 400 million, for a total of about $1 billion a year. These excessive costs are not necessarily expected to turn around quickly. The CA ISO CEO suggests that the CA ISO develop a transmission plan that identifies these deficient areas and the transmission projects that would resolve these issues. The CA ISO would develop five- and ten-year projections. The five-year view is more focused on RMR and congestion issues. The ten-year view would consider longer-term projects like 230 and 500 kV lines.[57]

- The CA ISO believes that it can make good judgments about identifying transmission projects, with the intention of choosing those that will minimize the costs at least within the CA ISO service territory, with the information it has.

- The CA ISO intends to develop its first five- and ten-year plan before January 2006. It would be approved shortly thereafter. New PTO plans based upon the CA ISO studies would be submitted to the CA ISO by July 1, 2006. CA ISO will still need to collect information about resource portfolios, such as load data and types of contracts. The CA ISO would lead a stakeholder process to help collect this information.

- If PTOs include CA ISO-proposed projects in their respective plans, then the CA ISO Board would approve them. If PTOs choose not to build them, the CA ISO would then go to a third party and use a request for proposal (RFP) process (that would need to be developed) to build them. The intent is that the CA ISO could move forward to get the projects built.

- One consideration that needs to be addressed in the plans is the resources side and the generation siting. The CA ISO plan should send a signal to resource developers that if they sited resources in certain locations, it would either defer or eliminate the need for transmission investment.

The California Department of Water Resources, State Water Project (SWP), the League of California Cities (LCC), the California State Association of Counties (CSAC), the Regional Council of Rural Counties, LADWP, and Vulcan Power submitted written comments by the August 4, 2005, deadline. Written comments are summarized below and are available online.[58]

Oral Comments Received at Hearing

TURN provided two comments on the staff report:[59]

- Regarding reliability criteria, it is important to keep in mind that one-in-ten is a 20 percent reserve for Los Angeles, but in the Sacramento Municipal Utility District (SMUD) territory, it is to a reserve margin of less than 15 percent since SMUD's single largest contingency facility is proportionately much smaller.

- Even if it becomes possible to make reasonable estimates of some of the "extreme" benefits, such as insurance and other quantifiable benefits, applying a social discount rate to the stream of benefits measured in a benefit cost analysis should be done cautiously. While this approach may be appropriate in some circumstances it could be "a very heavy thumb to put on the scale of benefit/cost analysis." Customers may end up with a fixed cost for a project that will increase customer rates over time. Commissioner Geesman suggested "that you should be equally cautious about burdening those who will be paying extra costs if the project does not go forward." TURN agreed and explained that applying the social discount rate is something to approach cautiously to avoid double counting or risk approval of a project that raises rates without providing comparable benefits.

Flynn RCI provided the following comments on the staff report:[60]

- When looking at the total economics of transmission within load pockets, the only publicly available numbers were the RMR fixed costs. The last time those costs were counted, the fixed costs in the Bay Area were just under $200 million. The numbers in the Transmission Staff Report quoting the CA ISO are greater than that. "They take into account other things. And I easily accept those." Flynn RCI supported the Energy Commission's broad review of the issues. Some issues are simpler than others, and that "If you really want to go after the low-hanging fruit," consider RMR and local congestion costs.[61]

- People do not understand how little has been done in the economic area. Studies were developed for Path 26 using the TEAM methodology which took at least two years. The PVD2 project is currently in permitting. Flynn RCI is interested in what it takes to reduce $1 billion in local reliability costs.

- Flynn RCI stated that "my basic message was to try to encourage the [Energy] Commission to align its recommendations with a lot of the earlier part of its report where it pointed out how big an issue this is from an economic standpoint. And I got to tell you, you know, hearing what Gary [DeShazo] had to say, I feel like ... celebrating. I mean it sounds like the [CA] ISO is really going to take a leadership role in this area … [So] my recommendation to the [Energy] Commission is to, as you've talked about having a cooperative relationship, basically do everything you can to help move that process along at a rapid pace."[62]

Written Comments on Transmission Staff Report and Strategic Plan

California Department of Water Resources, State Water Project

The California Department of Water Resources, State Water Project (SWP) provided written comments on the Transmission Staff Report. These comments are available online. A summary of its comments follows:

- The costs of constructing transmission and the allocation of those costs should be considered. The Energy Commission and others must encourage full consideration of all economic aspects and alternatives, including the costs of generation, in making decisions on investments in the grid.

- SWP generally agrees with the proposal (in Chapter 6 of the Transmission Staff Report) that the new CA ISO planning process allow the CA ISO to evolve from a predominantly reactive role to a more proactive one. Because of confidential information available to the CA ISO, including the requisite modeling tools, the CA ISO is best suited to provide a more comprehensive basis for determining the economic impacts of congestion and RMR-type costs, and to make decisions about new facilities that would provide economic and/or reliability benefits. The Energy Commission would complement CA ISO’s effort by coordinating the collection of this data from various parties and conducting related load growth studies.

- Transmission pricing policies should encourage cost-efficient development of transmission and generation alternatives to send price signals through application of principles of cost causation. These would serve as locational signals to generators to develop resource opportunities in locations that would best resolve transmission bottlenecks.

- The costs of congestion and reliability have skyrocketed in the past few years. It is important to adopt a proactive grid management stance that will minimize costs to market participants. Early identification and implementation of projects that will eliminate or lessen the impact of these costs will also help market participants to manage their costs. Those measures in Appendix F (of the Transmission Staff Report) will be helpful.

- Other mitigation measures such as demand response should be considered to solve short-term transmission problems until necessary transmission is built. Demand response should also be considered as an alternative for long-term transmission problems in locations where demand response is more economical than transmission expansion.

- There is a need for integrating transmission in developing renewable resources, and supports the principles of cost causation for these resources. Under these principles, FERC’s Large Generator Interconnection Policy (Order 2003) addresses this issue and provides guidance under which the customers of the generator(s), both wholesale and retail, pay the costs of generator interconnection through the cost of power purchased from the generator(s).

League of California Cities, the California State Association of Counties and the Regional Council of Rural Counties

The League of California Cities (LCC), the California State Association of Counties (CSAC) and the Regional Council of Rural Counties (RCRC) provided written comments on both the May 19 workshop and the July 28 hearing. Their July 28 letter repeated several comments from their May 19 letter that these organizations felt were not accurately portrayed in the Transmission Staff Report, and should be considered in a strategic transmission plan. Some of the issues raised in their August 2 comment letter include:

- The organizations would like a serious discussion of the issues they raised.

- A true collaborative process should reach out to interested stakeholders beyond utilities and others who routinely attend Energy Report workshops and hearings, including local agencies and the public.

- They support the establishment of corridor study groups in areas where a need has been identified.

- They prefer that utilities, local agencies, stakeholders, and the public work together to identify potential corridors, rather than imposing the proposed heavy-handed corridor designation process.

- They support the notion of land banking so that utilities may keep land for future needs in the rate base beyond the current five-year limit.

- They believe that a higher priority for the state should be to dismantle barriers to funding transmission infrastructure rather than to set aside privately held land without a means to fund its acquisition. They are concerned about the state tying up land for an indeterminate length of time without landowner compensation.

- They would like to see a discussion item that includes the appropriateness of utilities to acquire private land for a “corridor,” as opposed to a “route,” which ratepayers would ultimately pay for.

- They ask what the “incentive” for a utility is to acquire land for a “corridor” as opposed to a “route.” They are concerned that land use limitations prohibiting incompatible land uses in “designated corridors” would devalue that land and promote the acquisition of more land than is actually needed for a project right-of-way.

- They oppose any preemption of local land use authority and the requirement that local governments amend their general plans to be consistent with the designation of a transmission corridor. General plan updates are very expensive and the funds could be better utilized locally. Of great concern is potential enforcement of “incompatible uses” in these corridors, and the possibility of “takings” lawsuits against local governmental entities.

- They would like to see corridors clearly defined, and more importantly, these organizations cannot support any proposal that does not define an outer limit or maximum width.

- They support the need to identify future corridors in a strategic transmission plan over the corridor designation proposal in SB 1059.

Los Angeles Department of Water and Power

In a letter docketed August 5, 2005, LADWP provided written comments with details about its transmission siting process as a municipally-owned utility and participant in the Public Power Initiative of the West’s (PPIW) *Policies for the Successful Implementation of Transmission Plans within the Western Interconnection*. These policies are attached to the letter, which can be found online. Many of these comments were also made in LADWP's July 28 presentation. The letter chronicles its coordination with SCE noting the synergy between the two utilities which began in 1948 and continues to the present. Other points follow:

- LADWP has cooperated with the CA ISO in joint projects with other PTOs and this cooperation will continue when future transmission needs coincide with those PTOs. The considerations must include: deliverability - with the line in service, power up to LADWP's full entitlement must be able to be scheduled and delivered; no locational marginal pricing (LMP) or related charges should accrue to LADWP; losses should be determined in the project agreement, not subject to LMP principles; and the project agreement should be for the life of the project.

- "The designation of new transmission corridors within California is an exceedingly valuable undertaking"; and LADWP looks forward to participating in the designation of utility corridors. In the Navigant Consulting's presentation, the consultants failed to apply the criteria articulated in the Transmission Staff Report for qualifying transmission. The criteria include least cost, reliability, risk, market efficiency, fuel diversity, and resource flexibility. The CA ISO should apply these criteria to the CA ISO-controlled grid. "Many of the problems associated with inadequate transmission assets in California stem from the unique problems created by the assignment of operational control of transmission owned by the independently [*sic*] owned utilities (IOUs) to the CA ISO as a result of deregulation in California."

- Relative to LMP used by the CA ISO, the CA ISO creates its own set of problems because it is distinctly different from the prevailing physical model for transmission access utilized by the rest of the western interconnection. At least in the West, the use of a LMP model has increased cost, reduced reliability, and has not provided price signals to increase investment in transmission.

Vulcan Power

Comments on strategic planning issues and the Transmission Staff Report from Vulcan Power were posted to the docket for this proceeding on August 5, 2005. Vulcan is a developer of geothermal baseload generation resources in the Western region of the United States, particularly California. Vulcan's comments follow:

- Vulcan has executed a power purchase agreement with SCE for the purchase and sale of up to 120 MW of baseload geothermal generation, and has completed negotiating power purchase agreements with other California utilities.

- The Transmission Staff Report should have recognized the State's full geothermal potential. The full potential of these resources cannot be developed due to transmission constraints yet no mention is made of this in the staff report.

- The Energy Commission should immediately order the formation of a transmission study groups to deal with well-known transmission constraints and provide recommendations for alleviating these constraints, including the estimated cost of upgrades.

- The Energy Commission should order the formation of a transmission corridor study group to provide recommendations for implementing north of Lugo system upgrades. The Energy Commission would then be in a position to conduct an economic feasibility analysis and ensure that California is developing its full renewable potential through the most economic means possible.

- The Transmission Staff Report should have discussed the transmission constraints that prevent these resources from being developed. Vulcan mentioned that they have provided prior testimony regarding the geothermal potential in Siskiyou, Shasta, Lake, Sonoma, Mono, and Inyo counties and directly across the border in Nevada and Oregon. It is general knowledge and has been documented that a minimum of 1,400 MW or more of these cost-effective resources are located outside the Imperial Valley.

- The Transmission Staff Report should have recommended the formation of a transmission study group to address these transmission issues. Two additional transmission working groups should be formed: one for SCE's service territory, which would address constraints outside Tehachapi and Imperial Valley, and one to address transmission constraints in Northern California. Each of the transmission working groups should submit reports to the Energy Commission by November 2005, for use in its 2005 Energy Report.

Endnotes

[1] California Energy Commission, *Upgrading California's Electric Transmission System: Issues and Action for 2005 and Beyond*, July 2005. CEC 700-2005-018.
[2] Transcripts: July 28, 2005 Re:Strategic Transmission Planning Issues and Transmission Staff Report Hearing. Docket No. 04-IEP-01F.
[3] [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#2005meetings].
[4] Ibid. [pp. 8-10].
[5] Ibid. [p. 13]
[6] Ibid. [p. 29]
[7] Ibid. [p. 32]
[8] Navigant Consulting, July 28, 2005, PowerPoint presentation entitled "Part 1 Strategic Transmission Planning Issues" [http://www.energy.ca.gov/2005_energypolicy/documents/2005-07-28_hearing/presentations/NAVIGANT_2005-07-28.PDF]. (October 12, 2005).
[9] Ibid. [p.158]
[10] Ibid. [p.159]
[11] Ibid. [pp. 47-80, presentation slide 16]
[12] California Energy Commission, *Proposed Criteria for Evaluation of Transmission and Alternative Resources*, October 2005. CEC-700-2005-024. [http://www.energy.ca.gov/2005publications/CEC-700-2005-024/CEC-700-2005-024.PDF].
[13] California Energy Commission, *Assessing Low-Probability, High-Impact Events*, October 2005. CEC-700-2005-020-F. [http://www.energy.ca.gov/2005publications/CEC-700-2005-020/CEC-700-2005-020-F.PDF].
[14] Ibid [p. 84]
[15] Ibid. [p. 82]
[16] Ibid. [p. 83]
[17] Ibid. [p. 85]
[18] Ibid. [p. 88]
[19] Ibid. [p. 89]
[20] Ibid. [p.92]. The Sunrise Powerlink 500 kV project was announced by SDG&E September 7, 2005.
[21] Ibid. [p. 89]
[22] Ibid. [p. 86]
[23] Ibid. [p.89]
[24] [pp. 90-91]
[25] Ibid. [p. 91]
[26] Ibid. [p. 92]
[27] Ibid. [p. 93]
[28] Imperial Irrigation District, July 28, 2005, PowerPoint presentation entitled "IID Energy: Facing the Transmission Challenges of Tomorrow" [http://www.energy.ca.gov/2005_energypolicy/documents/2005-07-28_hearing/presentations/IID_BARBERA_2005-07-28.PDF]. (October 12, 2005).
[29] Ibid. [p. 103]
[30] Ibid. [p. 106]
[31] Ibid. [pp. 108-121]
[32] Ibid. [p. 109]
[33] Ibid. [pp.110-111]
[34] Ibid. [p.111]
[35] Ibid. [p.111]
[36] Ibid. [p. 113]
[37] Ibid. [p.115]
[38] Ibid. [p.116]
[39] Letter, Randy S. Howard (Executive Assistant to the Chief Operating Officer – Power System), "Comments of the Los Angeles Department of Water and Power on the CEC Staff Report, Upgrading

California's Electric Transmission System (CEC 700-2005-018) and other discussion at the committee hearing on strategic transmission planning issues held on July 28, 2005." August 5, 2005 [http://www.energy.ca.gov/2005_energypolicy/documents/2005-07-28_hearing/comments/HOWARD_LADWP_2005-08-05.pdf]. (October 12, 2005).

[40] Ibid [p.158]
[41] Ibid. [p.159]
[42] Ibid. [p161]
[43] Ibid. [p.161]
[44] Ibid. [p.162]
[45] Ibid. [p. 163]
[46] Ibid. [p. 166]
[47] Ibid. [pp. 170-173]
[48] Ibid. [p. 170]
[49] Ibid. [p.178]
[50] Ibid [pp. 173-174]
[51] Ibid. [pp.174-175]
[52] Ibid. [p. 176]
[53] Ibid. [p.179]
[54] Ibid. [pp. 183-186]
[55] Ibid. [pp.187 – 203]
[56] Ibid. [p. 190]
[57] Ibid. [p. 192]
[58] See: [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#072805].
[59] Ibid. [pp. 204-208]
[60] Ibid. [pp. 209-211]
[61] Ibid. [p. 210]
[62] Ibid. [p. 211]